Statement of Basis

Permit to Construct No. P-2011.0040
Project ID 61683

The Amalgamated Sugar Company LLC - Paul
Paul, Idaho

Facility ID 067-00001

Final

June 8, 2017
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Permit Writer

The purpose of this Statement of Basis is to satisfy the requirements of IDAPA 58.01.01.et seq, Rules for the Control of Air Pollution in Idaho, for issuing air permits.

ACRONYMS, UNITS, AND CHEMICAL NOMENCLATURE

AAC	acceptable ambient concentrations
AACC	acceptable ambient concentrations for carcinogens
acfm	actual cubic feet per minute
ASTM	American Society for Testing and Materials
Btu	British thermal units
CAA	Clean Air Act
cfm	cubic feet per minute
CFR	Code of Federal Regulations
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	CO_2 equivalent emissions
CSB	Concentrated separator byproduct
DEQ	Department of Environmental Quality
dscf	dry standard cubic feet
EL	screening emission levels
EPA	U.S. Environmental Protection Agency
GHG	greenhouse gases
gph	gallons per hour
gpm	gallons per minute
gr	grains (1 lb = 7,000 grains)
HAP	hazardous air pollutants
hr/yr	hours per consecutive 12 calendar month period
IDAPA	a numbering designation for all administrative rules in Idaho promulgated in accordance with the Idaho Administrative Procedures Act
km	kilometers
lb/hr	pounds per hour
lb/qtr	pound per quarter
m	meters
MACT	Maximum Achievable Control Technology
MMBtu	million British thermal units
MMscf	million standard cubic feet
NAAQS	National Ambient Air Quality Standard
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO_2	nitrogen dioxide
NO_X	nitrogen oxides
NSPS	New Source Performance Standards
O_2	oxygen
PC	permit condition
PM	particulate matter
$PM_{2.5}$	particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers
PM_{10}	particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
POM	polycyclic organic matter
ppm	parts per million
ppmw	parts per million by weight
PSD	Prevention of Significant Deterioration
PTC	permit to construct
PTC/T2	permit to construct and Tier II operating permit
PTE	potential to emit
Rules	*Rules for the Control of Air Pollution in Idaho*
scf	standard cubic feet
SCL	significant contribution limits

SIP	State Implementation Plan
SM	synthetic minor
SM80	synthetic minor facility with emissions greater than or equal to 80% of a major source threshold
SO_2	sulfur dioxide
SO_x	sulfur oxides
T/day	tons per calendar day
T/hr	tons per hour
T/yr	tons per consecutive 12 calendar month period
T2	Tier II operating permit
TAP	toxic air pollutants
TASCO	The Amalgamated Sugar Company LLC
ULSD	ultra-low sulfur diesel
U.S.C.	United States Code
VOC	volatile organic compounds
yd^3	cubic yards
$\mu g/m^3$	micrograms per cubic meter

FACILITY INFORMATION

Description

The Amalgamated Sugar Company LLC - Paul (TASCO) operates an existing beet sugar manufacturing plant that processes sugar beets into refined sugar, which is located in Paul, Idaho. The facility is also known as the Mini-Cassia Facility. Sugar beet processing operations consist of several steps, including diffusion, juice purification, evaporation, crystallization, molasses sugar recovery, and dried pulp manufacturing.

Prior to removing sucrose from sugar beets by diffusion, the cleaned and washed beets are sliced into long, thin strips called cossettes. In the diffusion step, the cossettes are conveyed to a continuous diffuser, in which hot water is used to extract sucrose. The sugar-enriched water that flows from the outlet of the diffuser is called "raw juice" and contains between 13% to 18% sugar. The raw juice proceeds to the juice purification operation. The processed cossettes, or pulp, leaving the diffuser is conveyed to the dried pulp manufacturing operation.

In the juice purification step, non-sucrose impurities in the raw juice are removed so that the pure sucrose can be crystallized. First, the juice passes through screens to remove any small cossette particles. The juice is then heated to 80-85°C (176-185°F) and proceeds to the liming system. In the liming system tank, milk of lime [$Ca(OH)_2$ aqueous solution] is added to the juice to absorb or adhere to the impurities. The juice is then sent to the first carbonation tank, where carbon dioxide (CO_2) gas is bubbled to precipitate the lime as insoluble calcium crystals. The lime kiln is used to produce the CO_2 and the lime, which are both used in carbonation; the lime is converted to milk of lime in a lime slaker. After filtration, the juice is softened. Then a small amount of sulfur dioxide (SO_2) is added to the juice to inhibit reactions that lead to darkening of the juice. Burning elemental sulfur in a sulfur stove produces the SO_2. Following the addition of SO_2, the juice (known as "thin juice") proceeds to the evaporators.

In the evaporation step, the sucrose in the juice is concentrated by removing water in a series of evaporators. Steam from boilers heats the first evaporator, and the steam from the water evaporated in the first evaporator heats the second evaporator, and so on through the final evaporator. After evaporation, the percentage of sucrose in the thick juice is 65% to 75%. Some of this thick juice is sent to storage tanks. Most of the thick juice is combined with crystalline sugars produced later in the process and dissolved in the high melter. The mixture is then filtered, yielding a clear liquid known as standard liquor, which proceeds to the crystallization operation.

In the crystallization step, sugar is crystallized by low-temperature pan boiling. The standard liquor is boiled in vacuum pans until it becomes supersaturated. To begin crystal formation, the liquor is "seeded" with finely milled sugar. When the crystals reach the desired size, the mixture of liquor and crystals, known as massecuite or fillmass, is discharged to the mixer. From the mixer, the massecuite is poured into high-speed centrifuges, in which the liquid is centrifuged into the outer shell, and the crystals are left in the inner centrifugal basket. The sugar crystals are washed with pure hot water, and then sent to the granulator/cooling system. After cooling, the sugar is screened and then either packaged or stored in large silos for future packaging. The liquid that was separated from the sugar crystals in the centrifuges is called syrup. This syrup is feed liquor for the second boiling step and is introduced back into a second set of vacuum pans. The crystallization/centrifugation process is repeated once again, resulting in the production of molasses.

In the molasses sugar recovery step, the molasses produced in the third boiling step can be used in the production of livestock feed. This molasses can be further desugarized using a separator process. However, the Mini Cassia facility does not have a separator so molasses is shipped to other factories for separation. The products of the separator process are "extract" (the high sugar fraction) and – "concentrated separator by product" (CSB, the low sugar fraction). The extract can be stored in tanks or immediately processed in the sugar operation, like thick juice. CSB can be used in the liquid form as livestock feed or can be added to the pulp.

In the dried pulp manufacturing step, wet pulp from the diffusion process is mechanically pressed to reduce the moisture content from about 95% to 75%. After pressing, the pulp can be sold as cattle feed or sent to the dryers. Before entering the rotary drum dryers, CSB or molasses is added to the pressed pulp. The pressed pulp is then dried by hot air in horizontal rotating drums known as pulp dryers. The pulp dryers can be fired by natural gas or coal. The dried pulp product is typically pelletized, but can be sold as livestock feed in both pelletized and unpelletized form.

Permitting History

The following information was derived from a review of the permit files available to DEQ. Permit status is noted as active and in effect (A) or superseded (S).

March 19, 1981	13-1020-0001-00, Air pollution source permit which established requirements for the boilers, Permit status (S)
January 1, 1984	1020-0001, Permit revision which established requirements for the pulp dryers, Permit status (S)
September 23, 2002	P-020407, PTC modification to add No. 6 evaporator and establish throughput limits, Permit status (S)
December 12, 2002	T1-9503-039-1, Initial T1 operating permit, Permit status (S)
February 3, 2005	P-050401, Revised PTC to replace the sugar production limit with a stead production limit, Permit status (S)
July 27, 2005	P-050406, Initial PTC for the Nebraska Boiler (backup), Permit status (A)
September 23, 2005	T1-030416, Renewal and administrative amendment T1 to incorporate compliance schedule and revisions resulting from an appeal, Permit status (S)
November 17, 2005	P-050424, Initial PTC to add temporary emergency generator, Permit status (T) (terminated)
December 15, 2005	P-050421, Revised PTC to increase daily throughput limit, Permit status (S)
June 14, 2006	P-060404, Revised PTC to increase annual throughput limit, Permit status (S)
May 16, 2007	P-2007.0023, Revised PTC to temporarily increase steam production in 2006, Permit status (S)
September 22, 2010	P-2010.0043, Initial PTC to replace lime kiln system, Permit status (S)
March 8, 2011	P-2011.0040, Revised PTC to revise campaign year definition, Permit status (S)
June 1, 2012	P-2011.0043, Revised PTC to revise slaker control equipment, Permit status (S)
June 11, 2012	P-2011.0040, Revised PTC to increase annual throughput and steaming rate limits, Permit status (S)
March 18, 2014	P-2011.0043, Revised PTC to remove slaker control equipment, Permit status (A)
August 13, 2014	P-2011.0040, Revised PTC to convert boilers to natural gas firing only and to establish limits to resolve a historic equipment review required by T1-030416 compliance schedule, Permit status (A, but will become S upon issuance of this permit)
October 15, 2014	T1-050414, Renewal T1 to incorporate CAM and PTC revisions, Permit status (A)

Application Scope

This PTC is for a modification at an existing Tier I facility.

The applicant has proposed to:

- Increase the daily and annual beet slice throughput limits;
- Eliminate the annual boiler steam production limit; and
- Install a new juice storage tank.

Application Chronology

March 23, 2016	DEQ received an application and an application fee.
April 6, 2016	DEQ determined that the application was incomplete.
April 14, 2016	DEQ received supplemental information from the applicant.
May 13, 2016	DEQ determined that the application was complete.
August 2, 2016	DEQ and TASCO entered into a consent order in order for TASCO to operate and not be in violation of P-2011.0040 issued August 13, 2014.
September 27, 2016	DEQ received an addendum to the application addressing consent order condition 18.A.
December 14, 2016	DEQ made available the draft permit and statement of basis for peer and regional office review.
December 21, 2016	DEQ made available the draft permit and statement of basis for applicant review.
March 13 – April 12, 2017	DEQ provided a public comment period on the proposed action.
April 20, 2017	DEQ provided the proposed permit and statement of basis for EPA review.
January 17, 2017	DEQ received the permit processing fee.
June 8, 2017	DEQ issued the final permit and statement of basis.

TECHNICAL ANALYSIS

Emissions Units and Control Equipment

Table 1 EMISSIONS UNIT AND CONTROL EQUIPMENT INFORMATION

Source Description		Control Equipment	Installation Date
B&W Boiler (S–B1) Operational capacity: Fuel:	 175,000 lb/hr steam natural gas	None	1952
Erie City Boiler (S–B2) Operational capacity: Fuel:	 250,000 lb/hr steam (gas) natural gas	None	1964
Nebraska Boiler (S–B3, Backup Boiler Only) Operational capacity: Fuel consumption: Fuels:	 200,000 lb/hr steam 250 MMBtu/hr natural gas	None	2005
North Pulp Dryer (S–D2) PW input rate: Coal consumption: Fuels:	 56.9 T/hr 5.7 T/hr coal and/or natural gas	Dryer exhaust is split between two cyclones (A–D2A) that operate in parallel. Cyclone exhaust is D2A) that operate in parallel. Cyclone exhaust is combined and then split between two	1969

Source Description		Control Equipment	Installation Date
		Spray-Impingement Scrubbers (A–D2B) that operate in parallel.	
South Pulp Dryer (S–D1) PW input rate: Coal consumption: Fuels:	 48.5 T/hr 4.9 T/hr coal and/or natural gas	Dryer exhaust is split between two cyclones (A–D1A) that operate in parallel. Cyclone exhaust is combined and then split between two Spray-Impingement Scrubbers (A–D1B) that operate in parallel.	1961
Pellet Cooler No. 1 (S–D3) Manufacturer/Model: PW input rate:	 California Pellet Mill/2GA3 7.5 T/hr	Cyclone (A–D3)	Pre 1970
Pellet Cooler No. 2 (S–D4) Manufacturer/Model: PW input rate:	 California Pellet Mill/2GA3 7.5 T/hr	Cyclone (A–D4/5)	Pre 1970
Pellet Cooler No. 3 (S–D5) Manufacturer/Model: PW input rate:	 California Pellet Mill/2GA3 7.5 T/hr		1974
Lime Kiln (S–K1) Manufacturer: Model: Manufacture date: Maximum capacity: Maximum operation: Fuel: Fuel consumption:	 Eberhardt KR 8.0 (forced draft, vertical) 2011 770 T/day lime rock 146,300 T/yr lime rock anthracite coal and/or coke 55.2 T/day, 59 MMBtu/hr	Gas Washer First Carbonation Tank Second Carbonation Tank (A–K1)	2012
Process Slaker (S–K2) – Eberhardt Process Manufacturer: Model: Manufacture date: Maximum capacity: Maximum operation:	 May Foundry Eberhardt KR 8.0 2011 394 T/day CaO 74,860 T/yr CaO	None	2012
Drying Granulator (S–W1) Operational capacity:	 73 T/hr wet sugar	Scrubber (A–W1)	Pre 1952
Cooling Granulator No. 1 (S–W2) Operational capacity:	 73 T/hr wet sugar	Baghouse (A–W2)	Pre 1952
Cooling Granulator No. 2 (S–W3) Manufacturer/Model: Operational capacity:	 BMA FCP 16/6/6 85 T/hr wet sugar	Baghouse (A–W3)	2012
Process Sugar Handling System (S–W4)		Process Sugar Baghouses (A–W4)	1967
Bulk Loadout Sugar Handling System (S–W5)		Bulk Loadout Baghouses (A–W5)	1994

Emissions Inventories

Potential to Emit

Emission inventories provided in the application included emissions of federally regulated criteria pollutants and greenhouse gases, and state-regulated toxic air pollutants (TAP).

Summaries of these emission inventories are provided below and in Appendix A.

Actual-to-Projected-Actual Emissions

For this project, projected annual emissions from the B&W and Erie City boilers, main mill vent, and sulfur stove are expected to increase and are based on a beet campaign and juice run of 340 days. Increasing the maximum daily beet slice limit will not require any change to the capacity of the boilers to produce steam. As summarized in Table 2, upon completion of the beet slice increase project, criteria pollutant emissions are expected to increase.

The emission increases are not expected to exceed the significant thresholds; therefore, the beet slice increase project would not be applicable to PSD program requirements.

The permittee has elected to use 2015-2016 for the baseline year (Table 2) as this is the only time period when natural gas was used as the sole fuel source for the boilers. Refer to the PSD Classification (40 CFR 52.21) section for additional information.

Table 2 BEET SLICE INCREASE PROJECT EMISSION INCREASES

Description	CO [b] T/yr [d]	NO_x [b] T/yr [d]	SO_2 [b] T/yr [d]	PM [a][b] T/yr [d]	VOC [b] T/yr [d]	CO_2e [c] T/yr [d]
Baseline Actual Emissions [e]	108.9	227.6	0.84	10.1	7.3	163,910
Projected Actual Emissions [e]	128.3	267.0	2.09	11.9	22.0	193,279
Emission Increases [f]	19.4	39.4	1.25	1.8	14.7	29,369
Significance Thresholds [f]	*100*	*40*	*40*	*15*	*40*	*75,000*

a) PM, PM_{10}, and $PM_{2.5}$ emissions were estimated to be equivalent; significance threshold listed is for $PM_{2.5}$, the most stringent threshold when applying assumption.
b) Regulated NSR Pollutant as defined in 40 CFR 52.21(b)(50).
c) Tons of CO_2 equivalent emissions as defined in 40 CFR 52.21(b)(49).
d) Tons per "campaign year," as defined in Permit Condition 2.1.
e) Baseline and Projected Actual Emissions estimates include the B&W and Erie City Boilers, the main mill vent, and sulfur stove. Baseline actual emissions used were actual emissions during the campaign years 2015-2016.
f) Net emission increase and significant net emission increase thresholds as determined in accordance with 40 CFR §52.21(b)(40), 40 CFR 52.21(b)(23), and 40 CFR 52.21(b)(3)(i).

The beet slice increase project is therefore not expected to result in a PSD significant net emission increase. Baseline Actual Emissions (BAE) and Projected Actual Emissions (PAE) were determined using New Source Review (NSR) Prevention of Significant Deterioration (PSD) procedures and definitions set forth in 40 CFR 52.21(a)(2)(iv)(*c*) and 40 CFR 52.21(b).

Toxic Air Pollutant Emissions Increases

As summarized in Table 3, upon completion of the beet slice increase of 352,000 T/yr, no apparent increase in state-regulated toxic air pollutants (TAP) is expected, with the exception of acetaldehyde, formaldehyde, and ammonia. Although acetaldehyde, formaldehyde, and ammonia were estimated to exceed the emission screening level (EL), the applicant has demonstrated preconstruction compliance with TAP standards in accordance with IDAPA 58.01.01.210.

Table 3 TOXIC AIR POLLUTANTS EMISSION INCREASES

Toxic Air Pollutants	Carb Tank#1	Carb Tank #2	Evaporator Vent	Change in Annual Average Emissions Rates for Units at the Facility (lb/hr)	Screening Emission Level (lb/hr)	Exceeds Screening Level? (Y/N)
Acetaldehyde	6.86E-02	1.06E-01	1.76E-03	1.76E-01	3.0E-03	Yes
Formaldehyde	7.43E-04	8.40E-04	3.23E-05	1.62E-03	5.1E-04	Yes
Ammonia				53.5	1.2	Yes

Post Project HAP Emissions

Estimated hazardous air pollutant (HAP) emissions are expected to increase as a result of this permit revision request, including emissions of acetaldehyde and formaldehyde as provided above. The facility will remain classified as a major source of HAP emissions following this project (refer to the Title V Classification section for additional information concerning facility classification).

Ambient Air Quality Impact Analyses

As presented in the Modeling Memo in Appendix B, the estimated emission rates of acetaldehyde, formaldehyde, and ammonia from this project exceeded applicable screening emission levels (EL) and published DEQ modeling thresholds established in IDAPA 58.01.01.585-586 and in the State of Idaho Air Quality Modeling Guideline[1]. Refer to the Emissions Inventories section for additional information concerning the emission inventories.

The applicant has demonstrated pre-construction compliance to DEQ's satisfaction that emissions from this facility will not cause or significantly contribute to a violation of any ambient air quality standard. The applicant has also demonstrated pre-construction compliance to DEQ's satisfaction that the emissions increase due to this permitting action will not exceed any acceptable ambient concentration (AAC) or acceptable ambient concentration for carcinogens (AACC) for toxic air pollutants (TAP). A summary of the Ambient Air Impact Analysis for TAP is provided in Appendix A.

An ambient air quality impact analyses document has been crafted by DEQ based on a review of the modeling analysis submitted in the application. That document is part of the final permit package for this permitting action (see Appendix B).

REGULATORY ANALYSIS

Attainment Designation (40 CFR 81.313)

The facility is located in Minidoka County, which is designated as attainment or unclassifiable for $PM_{2.5}$, PM_{10}, SO_2, NO_2, CO, and Ozone. Refer to 40 CFR 81.313 for additional information.

Facility Classification

The AIRS/AFS facility classification codes are as follows:

For THAPs (Total Hazardous Air Pollutants) Only:

A = Use when any one HAP has actual or potential emissions ≥ 10 T/yr or if the aggregate of all HAPS (Total HAPs) has actual or potential emissions ≥ 25 T/yr.

SM80 = Use if a synthetic minor (potential emissions fall below applicable major source thresholds if and only if the source complies with federally enforceable limitations) and the permit sets limits ≥ 8 T/yr of a single HAP or ≥ 20 T/yr of THAP.

SM = Use if a synthetic minor (potential emissions fall below applicable major source thresholds if and only if the source complies with federally enforceable limitations) and the potential HAP emissions are limited to < 8 T/yr of a single HAP and/or < 20 T/yr of THAP.

B = Use when the potential to emit without permit restrictions is below the 10 and 25 T/yr major source threshold

UNK = Class is unknown

For All Other Pollutants:

A = Actual or potential emissions of a pollutant are ≥ 100 T/yr.

SM80 = Use if a synthetic minor for the applicable pollutant (potential emissions fall below 100 T/yr if and only if the source complies with federally enforceable limitations) and potential emissions of the pollutant are ≥ 80 T/yr.

SM = Use if a synthetic minor for the applicable pollutant (potential emissions fall below 100 T/yr if and only if the source complies with federally enforceable limitations) and potential emissions of the pollutant are < 80 T/yr.

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[1] Criteria pollutant thresholds in Table 2, State of Idaho Guideline for Performing Air Quality Impact Analyses, Doc ID AQ-011, September 2013.

B = Actual and potential emissions are < 100 T/yr without permit restrictions.

UNK = Class is unknown.

Table 4 REGULATED AIR POLLUTANT FACILITY CLASSIFICATION

Pollutant	Permitted PTE (T/yr)	Major Source Thresholds (T/yr)	AIRS/AFS Classification
PM	241.5	**100**	A
$PM_{10}/PM_{2.5}$	257.6	**100**	A
SO_2	127.5	**100**	A
NO_X	856.0	**100**	A
CO	2904.8	**100**	A
VOC	163.9	**100**	A
HAP (single)	88.68	**10**	A
HAP (Total)	107.48	**25**	A

Permit to Construct (IDAPA 58.01.01.201)

IDAPA 58.01.01.201 .....Permit to Construct Required

The permittee has requested that a PTC be issued to the facility for the modification. Therefore, a permit to construct is required to be issued in accordance with IDAPA 58.01.01.220. This permitting action was processed in accordance with the procedures of IDAPA 58.01.01.200-228.

Tier II Operating Permit (IDAPA 58.01.01.401)

IDAPA 58.01.01.401 .....Tier II Operating Permit

The application was submitted for a permit to construct (refer to the Permit to Construct section), and an optional Tier II operating permit has not been requested. Therefore, the procedures of IDAPA 58.01.01.400–410 were not applicable to this permitting action.

Title V Classification (IDAPA 58.01.01.300, 40 CFR Part 70)

IDAPA 58.01.01.301 .....Requirement to Obtain Tier I Operating Permit

The Amalgamated Sugar Company LLC (TASCO – Paul) is classified as a major facility as defined in IDAPA 58.01.01.008.10:

- The facility emits or has the potential to emit a regulated air pollutant in an amount greater than or equal to 100 T/yr;
- The facility emits or has the potential to emit a single regulated HAP in excess of 10 T/yr;
- The facility emits or has the potential to emit a combination of regulated HAP in excess of 25 T/yr.

Amalgamated Sugar (TASCO – Paul) has a fossil-fuel boiler (or combination thereof) of more than 250 MMBtu/hr heat input; therefore the boiler house (which includes the B&W Boiler, Erie City Boiler, and Nebraska Boiler) was classified as a designated facility as defined in IDAPA 58.01.01.006.30 and 40 CFR 52.21(b)(1)(i)(a), and fugitive emissions are required to be included when determining the major facility classification in accordance with IDAPA 58.01.01.008.10.c.i, and when determining project net emissions increases in accordance with IDAPA 58.01.01.007 and 40 CFR 52.21(b)(48)(ii).

This PTC was processed in accordance with IDAPA 58.01.01.209.05.c; the applicable requirements contained in this PTC will be incorporated into the Tier I operating permit pursuant to IDAPA 58.01.01.300–399.

Refer to Appendix A for a summary of the regulated air pollutant emission estimates provided in the application.

PSD Classification (40 CFR 52.21)

40 CFR 52.21 ..... Prevention of Significant Deterioration of Air Quality

Because the facility boiler house steam plant (which includes the B&W Boiler, Erie City Boiler, and Nebraska Boiler) has a fossil-fuel boiler (or combination thereof) of more than 250 MMBtu/hr heat input, the boiler house was classified as a designated facility as defined in IDAPA 58.01.01.006.30 and in 40 CFR 52.21(b)(1)(i)(a), and fugitive emissions are required to be included when determining the major facility classification in accordance with IDAPA 58.01.01.008.10.c.i, and when determining project net emissions increases in accordance with IDAPA 58.01.01.007 and 40 CFR 52.21(b)(48)(ii).

The boiler house and the facility are classified as an existing major stationary source as defined in 40 CFR 52.21(b), because the boiler house emits and the facility emits or has the potential to emit criteria pollutants in an amount greater than 100 T/yr (and greater than 250 T/yr).

IDAPA 58.01.01.205 ..... PERMIT REQUIREMENTS FOR NEW MAJOR FACILITIES OR MAJOR MODIFICATIONS IN ATTAINMENT OR UNCLASSIFIABLE AREAS.

40 CFR 52.21 ..... Prevention of significant deterioration of air quality.

40 CFR 52.21(a)(2) ..... Applicability procedures.

In accordance with §52.21(a)(2)(i), Prevention of Significant Deterioration (PSD) requirements apply to the construction of any new major stationary source or any project at an existing major stationary source in an area designated as attainment or unclassifiable.

This permit revision request was proposed for an existing major stationary source in an area designated as attainment or unclassifiable (refer to the Attainment Designation (40 CFR 81.313) section for additional information).

In accordance with §52.21(a)(2)(ii), the requirements of §52.21(j) through (r) apply to the construction of any new major stationary source or the major modification of any existing major stationary source, except as otherwise provided.

This permit revision was not considered a major modification as defined in §52.21(b)(2)(i), because it was not predicted to result in a significant net emissions increase as determined in accordance with §52.21(b)(40). The net emissions increases resulting from this permitting action were predicted to be less than the significant levels as defined in §52.21(b)(23)(i) and as provided above in Table 2.

Except as provided below, §52.21(j) through (r)(5) were not determined to be applicable to this project. Additional information concerning this determination is provided in the paragraphs below regarding the emissions increase and net emissions increase calculations.

Emissions increase

In accordance with §52.21(a)(2)(iv)(a), except as otherwise provided, a project is a major modification for a regulated NSR pollutant if it causes two types of emissions increases—a significant emissions increase (as defined in §52.21(b)(40)), and a significant net emissions increase (as defined in §52.21(b)(3) and (b)(23)).

As provided in Table 2, this permitting action was not predicted to cause a significant emissions increase or a significant net emissions increase.

In accordance with §52.21(a)(2)(iv)(b), the procedure for calculating (before beginning actual construction) whether a significant emissions increase (i.e., the first step of the process) will occur depends upon the type of emissions units being modified, according to §52.21(a)(2)(iv)(c) through (f). For these calculations, fugitive emissions (to the extent quantifiable) are included only if the emissions unit is part of one of the source categories listed in paragraph §52.21(b)(1)(iii) or if the emission unit is located at a major stationary source that belongs to one of the listed source categories. Fugitive emissions are not included for those emissions units located at a facility whose primary activity is not represented by one of the source categories listed in paragraph §52.21(b)(1)(iii) and that are not, by themselves, part of a listed source category. The procedure for calculating (before beginning actual construction) whether a significant net emissions increase will occur at the major

stationary source (i.e., the second step of the process) is contained in the definition in §52.21(b)(3). Regardless of any such preconstruction projections, a major modification results if the project causes a significant emissions increase and a significant net emissions increase.

The emissions units which were evaluated are part of a listed source category in §52.21(b)(1)(iii), and fugitive emissions were included in the emissions increase estimates. In accordance with §52.21(a)(2)(iv)(*c*), the actual-to-projected actual test was used for this project because it involves existing emissions units. A significant emissions increase of a regulated NSR pollutant is not expected. The sum of the difference between projected actual emissions (as defined in §52.21(b)(41) and baseline actual emissions (as defined in §52.21(b)(48) for this permitting action did not equal or exceed pollutant significance thresholds as defined in §52.21(b)(23) and as provided in Table 2.

TASCO has elected to use actual production data from the period that includes the 2015-2016 beet processing campaign for the purposes of determining baseline actual emissions of all regulated NSR pollutants.

Reasonable Possibility Standard

In accordance with §52.21(r)(6), except as otherwise provided in paragraph (r)(6)(vi)(b) of this section, the provisions of this paragraph (r)(6) apply with respect to any regulated NSR pollutant emitted from projects at existing emissions units at a major stationary source (other than projects at a source with a PAL) in circumstances where there is a reasonable possibility, within the meaning of paragraph (r)(6)(vi) of this section, that a project that is not a part of a major modification may result in a significant emissions increase of such pollutant, and the owner or operator elects to use the method specified in paragraphs (b)(41)(ii)(a) through (c) of this section for calculating projected actual emissions.

Because NSR pollutant emission increases were not estimated to exceed applicable significance thresholds as shown in Table 2, a "reasonable possibility" of exceeding significant thresholds is not anticipated.

NSPS Applicability (40 CFR 60)

The Nebraska boiler installed at the facility in 2005 is subject to 40 CFR 60 Subpart Db requirements.

NESHAP Applicability (40 CFR 61)

The facility is not subject to any NESHAP requirements in 40 CFR 61.

MACT Applicability (40 CFR 63)

The facility boilers (B&W Boiler, Erie City Boiler, and Nebraska Boiler) are subject to the requirements of 40 CFR 63 Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters ("Boiler MACT"), because they are industrial boilers located at a major source of HAP. TASCO-Paul is classified as a major source of HAP; refer to the Title V Classification (IDAPA 58.01.01.300, 40 CFR Part 70) section for additional information concerning facility classification. DEQ is delegated this Subpart.

The applicability analysis provided below addresses the boilers that comprise the beet slice increase project.

40 CFR 63, Subpart DDDDD ..... National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

§ 63.7480 What is the purpose of this subpart?

In accordance with §63.7480, this subpart establishes national emission limitations and work practice standards for hazardous air pollutants (HAP) emitted from industrial, commercial, and institutional boilers and process heaters located at major sources of HAP. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and work practice standards.

§ 63.7485 Am I subject to this subpart?

In accordance with §63.7485, you are subject to this subpart if you own or operate an industrial, commercial, or institutional boiler or process heater as defined in §63.7575 that is located at, or is part of, a major source of HAP, except as specified in §63.7491. For purposes of this subpart, a major source of HAP is as defined in §63.2, except that for oil and natural gas production facilities, a major source of HAP is as defined in §63.7575.

Because the permittee owns and operates industrial boilers at a major source of HAP and which are not specified under §63.7491, the requirements of this subpart are applicable.

§ 63.7490 What is the affected source of this subpart?

(a) This subpart applies to new, reconstructed, and existing affected sources as described in paragraphs (a)(1) and (2) of this section.

(1) The affected source of this subpart is the collection at a major source of all existing industrial, commercial, and institutional boilers and process heaters within a subcategory as defined in §63.7575.

(2) The affected source of this subpart is each new or reconstructed industrial, commercial, or institutional boiler or process heater, as defined in §63.7575, located at a major source.

(b) A boiler or process heater is new if you commence construction of the boiler or process heater after June 4, 2010, and you meet the applicability criteria at the time you commence construction.

(c) A boiler or process heater is reconstructed if you meet the reconstruction criteria as defined in §63.2, you commence reconstruction after June 4, 2010, and you meet the applicability criteria at the time you commence reconstruction.

(d) A boiler or process heater is existing if it is not new or reconstructed.

(e) An existing electric utility steam generating unit (EGU) that meets the applicability requirements of this subpart after the effective date of this final rule due to a change (e.g., fuel switch) is considered to be an existing source under this subpart.

The permittee owns and operates existing industrial boilers.

§ 63.7491 Are any boilers or process heaters not subject to this subpart?

The types of boilers and process heaters listed in paragraphs (a) through (n) of this section are not subject to this subpart.

(a) An electric utility steam generating unit (EGU) covered by subpart UUUUU of this part or a natural gas-fired EGU as defined in subpart UUUUU of this part firing at least 85 percent natural gas on an annual heat input basis.

(b) A recovery boiler or furnace covered by subpart MM of this part.

(c) A boiler or process heater that is used specifically for research and development, including test steam boilers used to provide steam for testing the propulsion systems on military vessels. This does not include units that provide heat or steam to a process at a research and development facility.

(d) A hot water heater as defined in this subpart.

(e) A refining kettle covered by subpart X of this part.

(f) An ethylene cracking furnace covered by subpart YY of this part.

(g) Blast furnace stoves as described in EPA-453/R-01-005 (incorporated by reference, see §63.14).

(h) Any boiler or process heater that is part of the affected source subject to another subpart of this part, such as boilers and process heaters used as control devices to comply with subparts JJJ, OOO, PPP, and U of this part.

(i) Any boiler or process heater that is used as a control device to comply with another subpart of this part, or part 60, part 61, or part 65 of this chapter provided that at least 50 percent of the average annual heat input during any 3 consecutive calendar years to the boiler or process heater is provided by regulated gas streams that are subject to another standard.

(j) Temporary boilers and process heaters as defined in this subpart.

(k) Blast furnace gas fuel-fired boilers and process heaters as defined in this subpart.

(l) Any boiler or process heater specifically listed as an affected source in any standard(s) established under section 129 of the Clean Air Act.

(m) A unit that burns hazardous waste covered by Subpart EEE of this part. A unit that is exempt from Subpart EEE as specified in §63.1200(b) is not covered by Subpart EEE.

(n) Residential boilers as defined in this subpart.

Because the permittee owns and operates industrial boilers at a major source of HAP and which are not specified under §63.7491, the requirements of this subpart are applicable.

§ 63.7495 When do I have to comply with this subpart?

(a) If you have a new or reconstructed boiler or process heater, you must comply with this subpart by April 1, 2013, or upon startup of your boiler or process heater, whichever is later.

(b) If you have an existing boiler or process heater, you must comply with this subpart no later than January 31, 2016, except as provided in §63.6(i).

(c) If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, paragraphs (c)(1) and (2) of this section apply to you.

> *(1) Any new or reconstructed boiler or process heater at the existing source must be in compliance with this subpart upon startup.*
>
> *(2) Any existing boiler or process heater at the existing source must be in compliance with this subpart within 3 years after the source becomes a major source.*

(d) You must meet the notification requirements in §63.7545 according to the schedule in §63.7545 and in subpart A of this part. Some of the notifications must be submitted before you are required to comply with the emission limits and work practice standards in this subpart.

(e) If you own or operate an industrial, commercial, or institutional boiler or process heater and would be subject to this subpart except for the exemption in §63.7491(l) for commercial and industrial solid waste incineration units covered by part 60, subpart CCCC or subpart DDDD, and you cease combusting solid waste, you must be in compliance with this subpart and are no longer subject to part 60, subparts CCCC or DDDD beginning on the effective date of the switch as identified under the provisions of §60.2145(a)(2) and (3) or §60.2710(a)(2) and (3).

(f) If you own or operate an existing EGU that becomes subject to this subpart after January 31, 2016, you must be in compliance with the applicable existing source provisions of this subpart on the effective date such unit becomes subject to this subpart.

(g) If you own or operate an existing industrial, commercial, or institutional boiler or process heater and would be subject to this subpart except for a exemption in §63.7491(i) that becomes subject to this subpart after January 31, 2013, you must be in compliance with the applicable existing source provisions of this subpart within 3 years after such unit becomes subject to this subpart.

(h) If you own or operate an existing industrial, commercial, or institutional boiler or process heater and have switched fuels or made a physical change to the boiler or process heater that resulted in the applicability of a different subcategory after the compliance date of this subpart, you must be in compliance with the applicable existing source provisions of this subpart on the effective date of the fuel switch or physical change.

(i) If you own or operate a new industrial, commercial, or institutional boiler or process heater and have switched fuels or made a physical change to the boiler or process heater that resulted in the applicability of a different subcategory, you must be in compliance with the applicable new source provisions of this subpart on the effective date of the fuel switch or physical change.

In accordance with §63.7491(b), because the boilers are existing boilers, the compliance deadline is January 31, 2016 (unless an extension is pursued in accordance with §63.6(i)).

§ 63.7499 What are the subcategories of boilers and process heaters?

The subcategories of boilers and process heaters, as defined in §63.7575 are:

(a) Pulverized coal/solid fossil fuel units.

(b) Stokers designed to burn coal/solid fossil fuel.

(c) Fluidized bed units designed to burn coal/solid fossil fuel.

(d) Stokers/sloped grate/other units designed to burn kiln dried biomass/bio-based solid.

(e) Fluidized bed units designed to burn biomass/bio-based solid.

(f) Suspension burners designed to burn biomass/bio-based solid.

(g) Fuel cells designed to burn biomass/bio-based solid.

(h) Hybrid suspension/grate burners designed to burn wet biomass/bio-based solid.

(i) Stokers/sloped grate/other units designed to burn wet biomass/bio-based solid.

(j) Dutch ovens/pile burners designed to burn biomass/bio-based solid.

(k) Units designed to burn liquid fuel that are non-continental units.

(l) Units designed to burn gas 1 fuels.

(m) Units designed to burn gas 2 (other) gases.

(n) Metal process furnaces.

(o) Limited-use boilers and process heaters.

(p) Units designed to burn solid fuel.

(q) Units designed to burn liquid fuel.

(r) Units designed to burn coal/solid fossil fuel.

(s) Fluidized bed units with an integrated fluidized bed heat exchanger designed to burn coal/solid fossil fuel.

(t) Units designed to burn heavy liquid fuel.

(u) Units designed to burn light liquid fuel.

In accordance with §63.7499(l), the B&W and Erie City boilers are existing boilers designed to burn Class 1 fuels (natural gas).

A complete analysis of NESHAP Subpart DDDDD will be included and incorporated into the Tier I operating permit.

Permit Conditions Review

This section describes only those permit conditions that have been added, revised, modified or deleted as a result of this permitting action.

Permit Condition 2.2 was revised to reflect that the new daily throughput of beets shall be 21,550 tons per day based on emission estimates and modeling provided by the Applicant.

Permit Condition 2.3 was revised to reflect that the new annual throughput of beets shall be 3,852,000 tons per campaign year based on emission estimates and modeling provided by the Applicant.

Existing Permit Conditions 2.5 and 2.6 were removed because the boilers are no longer capable of firing coal and therefore the boiler steam production limit is obsolete.

Existing Permit Conditions 2.7 through 2.9 were removed. In letters dated February 23, 2015 and April 24, 2015, the permittee provided notification to DEQ that the coal burners and coal delivery systems for the boilers have been removed.

Existing Permit Condition 2.10 was removed because the performance test for CO on the B&W Boiler was completed in February of 2016.

Existing Permit Conditions 2.13 and 2.14 were removed because the boilers no longer fire coal and the monitoring was required only through calendar year 2016.

Permit Condition 2.5 was revised to reflect updated language to clarify that any future New Source Review applicability determinations shall not use coal emissions under the PSD program.

New Permit Condition 3.1 describes the process for which the boilers are used.

New Permit Condition 3.2 describes the control devices for the existing boilers.

New Permit Condition 3.3 describes the annual emission limits for the B&W and Erie City Boilers. These emission limits were incorporated for PSD avoidance.

New Permit Condition 3.4 ensures that the opacity of the boiler stacks does not exceed 20%.

New Permit Condition 3.5 limits the boilers to combust natural gas only. This permit condition replaces a portion of existing Permit Condition 2.7.

New Permit Condition 3.6 limits the operation of the B&W and Erie City Boilers to demonstrate compliance with the emission limits.

New Permit Condition 3.7 outlines the recordkeeping to demonstrate compliance with the operating limits for the boilers.

Permit Conditions 3.8 and 3.9 have been renumbered from the existing Permit Conditions 2.11 and 2.12.

PUBLIC REVIEW

Public Comment Period

As required by IDAPA 58.01.01.209.05.c, a public comment period was made available to the public from March 13 – April 12, 2017. During this time, comments were submitted in response to DEQ's proposed action. A response to public comments document has been crafted by DEQ based on comments submitted during the public comment period. That document is part of the final permit package for this permitting action.

DEQ provided the proposed permit to EPA Region10 for its review and comment on April 20, 2017 via e-mail.

APPENDIX A – EMISSIONS INVENTORIES

Boiler Natural Gas Firing Projected Emissions Estimates
Beet Campaign 206 days & Juice Run 134 Days
The Amalgamated Sugar Co. LLC
Mini Cassia Facility

Source Name	Source ID	Nat. Gas Therms	Emissions				
			Parameter	Factor	Units	Reference	(tons/y)
B&W Boiler - Beet Campaign	S-B1	10,356,764	PM	7.2E-04	lbs/therm	AP-42,7/98, Table 1.4-2	3.73
		10,356,764	NOx	1.0E-02	lbs/therm	Based on 0.1 lbs/MMBtu	51.78
		10,356,764	SO2	6.0E-05	lbs/therm	AP-42,7/98, Table 1.4-2	0.311
		10,356,764	CO	7.4E-03	lbs/therm	AP-42, 7/98, Table 1.4-1	38.32
		10,356,764	VOC	5.2E-04	lbs/therm	AP-42,7/98, Table 1.4-2	2.69

Source Name	Source ID	Nat. Gas Therms	Emissions				
			Parameter	Factor	Units	Reference	(tons/y)
Erie City Boiler - Beet Campaign	S-B2	14,403,520	PM	7.2E-04	lbs/therm	AP-42,7/98, Table 1.4-2	5.19
		14,403,520	NOx	2.0E-02	lbs/therm	Feb. 2016 Eng. Test	144.04
		14,403,520	SO2	6.0E-05	lbs/therm	AP-42,7/98, Table 1.4-2	0.43
		14,403,520	CO	8.0E-03	lbs/therm	AP-42, 7/98, Table 1.4-1	57.61
		14,856,170	VOC	5.2E-04	lbs/therm	AP-42,7/98, Table 1.4-2	3.86

Source Name	Source ID	Nat. Gas Therms	Emissions				
			Parameter	Factor	Units	Reference	(tons/y)
B&W Boiler - Juice Run	S-B1	2,316,506	PM	7.2E-04	lbs/therm	AP-42,7/98, Table 1.4-2	0.83
		2,316,506	NOx	1.0E-02	lbs/therm	Based on 0.1 lbs/MMBtu	11.58
		2,316,506	SO2	6.0E-05	lbs/therm	AP-42,7/98, Table 1.4-2	0.069
		2,316,506	CO	7.4E-03	lbs/therm	AP-42, 7/98, Table 1.4-1	8.57
		2,316,506	VOC	5.2E-04	lbs/therm	AP-42,7/98, Table 1.4-2	0.60

Source Name	Source ID	Nat. Gas Therms	Emissions				
			Parameter	Factor	Units	Reference	(tons/y)
Erie City Boiler - Juice Run	S-B2	5,956,731	PM	7.2E-04	lbs/therm	AP-42,7/98, Table 1.4-2	2.14
		5,956,731	NOx	2.0E-02	lbs/therm	Feb. 2016 Eng. Test	59.57
		5,956,731	SO2	6.0E-05	lbs/therm	AP-42,7/98, Table 1.4-2	0.179
		5,956,731	CO	8.0E-03	lbs/therm	AP-42, 7/98, Table 1.4-1	23.83
		5,956,731	VOC	5.2E-04	lbs/therm	AP-42,7/98, Table 1.4-2	1.55

Total Therms **33,033,521**

Boiler Natural Gas Firing 2015 - 2016 Emissions Estimates
Beet Campaign 201 days & Juice Run 107 Days
The Amalgamated Sugar Co. LLC
Mini Cassia Facility

Source Name	Source ID	Nat. Gas Therms	Emissions				
			Parameter	Factor	Units	Reference	(tons/y)
B&W Boiler - Beet Campaign	S-B1	8,893,431	PM	7.2E-04	lbs/therm	AP-42,7/98, Table 1.4-2	3.20
		8,893,431	NOx	1.0E-02	lbs/therm	Based on 0.1 lbs/MMBtu	44.47
		8,893,431	SO2	6.0E-05	lbs/therm	AP-42,7/98, Table 1.4-2	0.267
		8,893,431	CO	7.4E-03	lbs/therm	AP-42, 7/98, Table 1.4-1	32.91
		8,893,431	VOC	5.2E-04	lbs/therm	AP-42,7/98, Table 1.4-2	2.31

Source Name	Source ID	Nat. Gas Therms	Emissions				
			Parameter	Factor	Units	Reference	(tons/y)
Erie City Boiler - Beet Campaign	S-B2	13,340,147	PM	7.2E-04	lbs/therm	AP-42,7/98, Table 1.4-2	4.80
		13,340,147	NOx	2.0E-02	lbs/therm	Feb. 2016 Eng. Test	133.40
		13,340,147	SO2	6.0E-05	lbs/therm	AP-42,7/98, Table 1.4-2	0.40
		13,340,147	CO	8.0E-03	lbs/therm	AP-42, 7/98, Table 1.4-1	53.36
		13,340,147	VOC	5.2E-04	lbs/therm	AP-42,7/98, Table 1.4-2	3.47

Source Name	Source ID	Nat. Gas Therms	Emissions				
			Parameter	Factor	Units	Reference	(tons/y)
B&W Boiler - Juice Run	S-B1	1,618,525	PM	7.2E-04	lbs/therm	AP-42,7/98, Table 1.4-2	0.58
		1,618,525	NOx	1.0E-02	lbs/therm	Based on 0.1 lbs/MMBtu	8.09
		1,618,525	SO2	6.0E-05	lbs/therm	AP-42,7/98, Table 1.4-2	0.049
		1,618,525	CO	7.4E-03	lbs/therm	AP-42, 7/98, Table 1.4-1	5.99
		1,618,525	VOC	5.2E-04	lbs/therm	AP-42,7/98, Table 1.4-2	0.42

Source Name	Source ID	Nat. Gas Therms	Emissions				
			Parameter	Factor	Units	Reference	(tons/y)
Erie City Boiler - Juice Run	S-B2	4,161,920	PM	7.2E-04	lbs/therm	AP-42,7/98, Table 1.4-2	1.50
		4,161,920	NOx	2.0E-02	lbs/therm	Feb. 2016 Eng. Test	41.62
		4,161,920	SO2	6.0E-05	lbs/therm	AP-42,7/98, Table 1.4-2	0.125
		4,161,920	CO	8.0E-03	lbs/therm	AP-42, 7/98, Table 1.4-1	16.65
		4,161,920	VOC	5.2E-04	lbs/therm	AP-42,7/98, Table 1.4-2	1.08

Total Therms **28,014,023**

Ammonia Emissions Estimate
2000 ton/d Beet Slice Increase
Mini Cassia Facility

To address the requirements of IDAPA 58.01.01.585, the net increase in ammonia emissions have been calculated as follows:

19,550 = tons/day - Daily beet slice production limitation (Condition 2.2 of PTC #P2011.0040)

21,550 = tons/day - Requested daily beet slice production limitation

2,000 = tons/day - Net daily production increase

83.3 = tons/hr - Net hourly production increase

0.642 = lbs. ammonia/ton beet slice[1]

53.5 = lbs. ammonia/hr - Net ammonia emissions

[1] The ammonia emission factor is based on previous estimates including the annual

Ammonia Estimates
Main Mill Sources
The Amalgamated Sugar Co. LLC - Mini Cassia Facility
2016 Ammonia AQIA Impact Anaysis

Source	Percent of Total	Percent of Source	Overall	Ammonia Emissions [1] 53.5 (lbs/h)
Carbonation Tanks	22.22%			
- 1st Carbonation Vent (PK1/2A)		50.00%	11.11%	5.9
- 2nd Carbonation Vent (PK1/2B)		50.00%	11.11%	5.9
Membrane Filters	11.11%			
- Filters Vent #1 (PF1)		14.29%	1.59%	0.8
- Filters Vent #2 (PF2)		14.29%	1.59%	0.8
- Filters Vent #3 (PF3)		35.71%	3.97%	2.1
- Filter Vent #4 (PF4)		35.71%	3.97%	2.1
Evaporator Vent (EVAP)	8.33%	100.00%	8.33%	4.5
Process Slaker	2.78%	100.00%	2.78%	1.5
Irrigation Lagoon & Cooling Towers	55.56%			
- Lagoon (ASP)		11.60%	6.44%	3.4
- Cooling Tower #1 Vent #1(PC1)		7.86%	4.37%	2.3
- Cooling Tower #1 Vent #2(PC2)		7.86%	4.37%	2.3
- Cooling Tower #2 Vent #1(PC3)		8.65%	4.81%	2.6
- Cooling Tower #2 Vent #2(PC4)		8.65%	4.81%	2.6
- Cooling Tower #3 Vent #1(PC5)		22.99%	12.77%	6.8
- Cooling Tower #3 Vent #2(PC6)		22.99%	12.77%	6.8
- Cooling Tower #4 Vent #1(PC7)		4.70%	2.61%	1.4
- Cooling Tower #4 Vent #2(PC8)		4.70%	2.61%	1.4

[1] From Appendix B & Appendix C of the August 16, 2002 Permit to Construct Application for the No. 6 Evaporator and updated based on the November 25, 2002 Drum Filter PTC Exemption Analysis Report and April 23,2004 Cooling Tower TAP Exemption Report.

Main Mill & Sulfur Stove
Net Annual Emissions Increases
Increase Annual Beet Slice by 352,000 tons/year
Mini Cassia Facility

352,000 = slice increase from 3,500,000 to 3,852,000 tons per year (tons/year)

Sulfur Stove

0.13 = lbs sulfur per ton beet slice (lbs/tons)
22.9 = tons additional sulfur per year thru sulfur stoves (tons/year)
0.006 = lbs SO2 per ton beets (lbs/ton) - 1992 Stack Test
1.1 = tons SO2 per year net increase from sulfur stoves (tons/year)

Main Mill

0.0756 = lbs VOC's per ton beets (lbs/ton) - engineering estimate
13.3 = tons VOC's per year net increase from main mill (tons/year)

Main Mill Vents
Net Annual Aldehyde Emissions Increases
Annual Beet Slice Increase by 352,000 tons/year
Mini Cassia Facility

Source	Acetaldehyde	Formaldehyde
Emission Factor[1] (lbs/tons beets)	2.47E-03	2.27E-05
Annual Beet Slice Increase (ton/yr)	352,000	352,000
Annual Emissions Increase (tons/y)	4.35E-01	4.00E-03
Annualized Emissions Increase (lbs/h)[2]		
-Total	1.76E-01	1.62E-03
-1st Carb Tank Vent	6.86E-02	7.43E-04
-2nd Carb Tank Vent	1.06E-01	8.40E-04
-Evaporator Vent	1.76E-03	3.23E-05
Screening Levels (IDAPA 58.01.01.586)	3.00E-03	5.10E-04

[1] Based on 2003 engineering stack testing data.

[2] Assume 206 d/y beet campaign.

APPENDIX B – AMBIENT AIR QUALITY IMPACT ANALYSES

MEMORANDUM

DATE: November 30, 2016

TO: **Kelli Wetzel**, Permit Writer, Air Program

FROM: Thomas Swain, Air Quality Modeler, Analyst 3, Air Program

PROJECT: The Amalgamated Sugar Company LLC (TASCO) facility in Paul, Idaho, Permit to Construct (PTC) P-2011.0040, Facility ID No. 067-0001

SUBJECT: Demonstration of Compliance with IDAPA 58.01.01.203.02 (NAAQS) and 203.03 (TAPs) as it relates to air quality impact analyses.

Contents

1.0 Summary

The Amalgamated Sugar Company LLC (TASCO) submitted an application for a Permit to Construct (PTC) on March 23, 2016, for modifications their existing facility located in Paul, Idaho. The facility is referred to as the TASCO Mini Cassia facility. As discussed later in this memorandum, TASCO submitted a final addendum for this permit on November 14, 2016.

TASCO is a facility that processes sugar beets into refined granulated sugar as well as feed products for both retail and commercial markets. The crop is harvested and processed generally in the fall and winter seasons. The main emission sources are the boilers, the pulp dryers, and the lime kilns. The facility is located one mile east of Paul, Idaho, and is situated on a large expanse of approximately 400 acres. This modification to the permit was requested to account for an increase in the daily beet throughput limitation from 19,550 tons/day (T/day) to 21,550 T/day. Additionally, the annual beet throughput limitation is requested to be increased from 3,5000,000 tons/year (T/yr) to 3,700,000 T/yr. TASCO is also installing a new juice storage tank to accommodate the proposed increase in beet throughput. Finally, an existing permit condition related to limiting boiler steam production is removed because it is no longer applicable, as coal is no longer used as a fuel at the facility.

The entire process is discussed in detail in the main body of the Department of Environmental Quality (DEQ) Statement of Basis supporting the issued proposed PTC. This modeling review memorandum provides a summary and approval of the ambient air impact analyses submitted with the permit application. It also describes DEQ's review of those analyses, DEQ's verification analyses, additional clarifications, and conclusions.

Project-specific air quality impact analyses involving atmospheric dispersion modeling of estimated emissions associated with the facility were submitted to DEQ to demonstrate that the facility would not cause or significantly contribute to a violation of any ambient air quality standard as required by IDAPA 58.01.01.203.02 and 203.03 (Idaho Air Rules Section 203.02 and 203.03).

TASCO performed the initial ambient air impact analyses for this project; the final modeling analyses was done by Stantec, an air permitting consultant, on behalf of TASCO. The analyses were performed to demonstrate compliance with air quality standards. The DEQ review summarized by this memorandum addressed only the rules, policies, methods, and data pertaining to the air impact analyses used to demonstrate that the estimated emissions increases at the facility associated with the proposed project will not cause or significantly contribute to a violation of any applicable air quality standard. This review did not evaluate compliance with other rules or analyses that do not pertain to the air impact analyses. Evaluation of emissions estimates is the responsibility of the permit writer and is addressed in the main body of the Statement of Basis. The accuracy of emissions estimates were not evaluated as part of DEQ's review of the air impact analyses and described in this modeling review memorandum.

A modeling protocol was not submitted for this project. A permit application was submitted on March 23, 2016. This application was determined to be incomplete on April 6, 2016, largely due to incomplete or missing forms. Several iterations of the application were submitted between April 6, 2016, and July 26, 2016. These were required to reflect condition 2.15 of the April 2014 PTC, where the applicant has been directed to not use emission decreases creditable to the removal of coal usage at the facility. These efforts are discussed in detail in section 3.3.2. On July 27, DEQ issued a consent order allowing TASCO to continue operations with proposed operational changes. On September 26, 2016, TASCO (and Stantec) submitted a modification of the application, in accordance with the consent order agreement. In the application TASCO provided revised emission rates, based on refined estimates of boiler emissions from periods of only natural gas usage. There were inconsistencies between the emissions in the modeling files and the PTE emissions

listed in the application. The number of days that the boilers will operate was slightly underestimated in the modeling files. Because of these emission differences, a final revision was submitted on November 14.

The final submitted air quality impact analyses: 1) utilized appropriate methods and models; 2) was conducted using reasonably accurate or conservative model parameters and input data (review of emissions estimates was addressed by the DEQ permit writer); 3) adhered to established DEQ guidelines for new source review dispersion modeling; 4) showed either a) that estimated potential/allowable emissions are at a level defined as below regulatory concern (BRC) and do not require a NAAQS compliance demonstration; b) that predicted pollutant concentrations from emissions associated with the project as modeled were below Significant Impact Levels (SILs) or other applicable regulatory thresholds; or c) that predicted pollutant concentrations from emissions associated with the project as modeled, when appropriately combined with co-contributing sources and background concentrations, were below applicable National Ambient Air Quality Standards (NAAQS) at ambient air locations where and when the project has a significant impact; 5) showed that Toxic Air Pollutant (TAP) emissions increases associated with the project will not result in increased ambient air impacts exceeding allowable TAP increments.

Table 1 presents key assumptions and results to be considered in the development of the permit.

Air impact analyses are required by Idaho Air Rules to be conducted according to methods outlined in 40 CFR 51, Appendix W (*Guideline on Air Quality Models*). Appendix W requires that facilities be modeled using emissions and operations representative of design capacity or as limited by a federally enforceable permit condition. The submitted information and analyses demonstrated to the satisfaction of the Department that operation of the proposed facility will not cause or significantly contribute to a violation of any ambient air quality standard, provided the key conditions in Table 1 are representative of facility design capacity or operations as limited by a federally enforceable permit condition.

Table 1. KEY ASSUMPTIONS USED IN MODELING ANALYSES

Criteria/Assumption/Result	Explanation/Consideration
General Emissions Rates. Emissions rates used in the modeling analyses, as listed in this memorandum, represent maximum potential emissions as given by design capacity or as limited by the issued permit for the specific pollutant and averaging period.	Compliance has not been demonstrated for emissions rates greater than those used in the modeling analyses.
Modeling Thresholds for Criteria Pollutant Emissions. Maximum long-term emissions of $PM_{2.5}$, and oxides of nitrogen (NOx) associated with the proposed project are above the Level 1 threshold for each pollutant. Therefore, a demonstration of compliance with NAAQS was done for these pollutants and averaging times.	Project-specific air impact analyses demonstrating compliance with NAAQS, as required by Idaho Air Rules Section 203.02, are required for pollutants having an emissions increase that is greater than Level I level modeling applicability thresholds. Compliance with NAAQS has not been demonstrated for emissions that exceed the emission estimates presented in the application.
TAPS Modeling. Emission rates of TAPS per Idaho Air Rules Sections 585 and 586 for Ammonia, Acetaldehyde, and Formaldehyde exceeded Emissions Screening Level (EL) rates.	Air impact analyses demonstrating compliance with TAPs allowable impact increments, as required by Idaho Air Rules Section 203.03, is required for pollutants having an emissions rate greater than Emissions Screening Levels (ELs). Therefore, a demonstration of compliance with TAPs increments was required.

2.0 Background Information

This section provides background information applicable to the project and the site where the facility is located. It also provides a brief description of the applicable air impact analyses requirements for the project.

2.1 Project Description

TASCO Mini Cassia is an existing facility near Paul, Idaho, which processes sugar beets and beet products into refined granulated sugar and feed products for commercial and retail products. This project was submitted as a modification to Permit to Construct (PTC) No. 067-0001. The facility intends to:

1) increase the daily slice limitation from 19,550 tons per day to 21,550 tons per day (a 10% increase);

2) increase the annual slice limitation from 3,500,000 to 3,700,000 tons (a 6% increase);

3) increase annual boiler operations for managing the slice increases and processing thick sugar in a newly installed juice tank.

TASCO's air impact analyses, as part of the permit application, was submitted to show that emissions increases associated with the proposed modification do not cause or contribute to an exceedance of any NAAQS or TAPs Acceptable Ambient Concentration (AAC) or Acceptable Ambient Concentration of a Carcinogen (AACC). A detailed description of the facility is listed in Section 1 of the submitted application.

2.2 Proposed Location and Area Classification

TASCO Mini Cassia is located one mile east of Paul, Idaho, in Township 9 South, Range 23 East. This area is designated as an attainment or unclassifiable area for sulfur dioxide (SO_2), nitrogen dioxide (NO_2), carbon monoxide (CO), lead (Pb), ozone (O_3), particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers (PM_{10}), and particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers ($PM_{2.5}$). The area is not classified as non-attainment for any criteria pollutants.

2.3 Air Impact Analyses Required for All Permits to Construct

Criteria Pollutant and TAP Impact Analyses for a PTC are addressed in Idaho Air Rules Sections 203.02 and 203.03:

> *No permit to construct shall be granted for a new or modified stationary source unless the applicant shows to the satisfaction of the Department all of the following:*
>
> ***02. NAAQS.*** *The stationary source or modification would not cause or significantly contribute to a violation of any ambient air quality standard.*
>
> ***03. Toxic Air Pollutants.*** *Using the methods provided in Section 210, the emissions of toxic air pollutants from the stationary source or modification would not injure or unreasonably affect human or animal life or vegetation as required by Section 161. Compliance with all applicable toxic air pollutant carcinogenic increments and toxic air pollutant non-carcinogenic increments will also demonstrate preconstruction compliance with Section 161 with regards to the pollutants listed in Sections 585 and 586.*

Atmospheric dispersion modeling, using computerized simulations, is used to demonstrate compliance with both NAAQS and TAPs. Idaho Air Rules Section 202.02 states:

Estimates of Ambient Concentrations. *All estimates of ambient concentrations shall be based on the applicable air quality models, data bases, and other requirements specified in 40 CFR 51 Appendix W (Guideline on Air Quality Models).*

2.4 Significant Impact Level and Cumulative NAAQS Impact Analyses

The Significant Impact Level (SIL) analysis for a new facility or proposed modification to a facility involves modeling estimated criteria air pollutant emissions from the facility or modification to determine the potential impacts to ambient air. Air impact analyses are required by Idaho Air Rules to be conducted per methods outlined in 40 CFR 51, Appendix W (Guideline on Air Quality Models). Appendix W requires that facilities be modeled using emissions and operations representative of design capacity or as limited by a federally enforceable permit condition.

A facility or modification is considered to have a significant impact on air quality if maximum modeled impacts to ambient air exceed the established SIL listed in Idaho Air Rules Section 006 (referred to as a significant contribution in Idaho Air Rules) or as incorporated by reference as per Idaho Air Rules Section 107.03.b. Table 2 lists the applicable SILs.

If modeled maximum pollutant impacts to ambient air from the emissions sources associated with a new facility or modification exceed the SILs, then a cumulative NAAQS impact analysis is necessary to demonstrate compliance with NAAQS and Idaho Air Rules Section 203.02.

DEQ has developed modeling applicability thresholds that effectively assure that project-related emissions increases below stated values will result in ambient air impacts below the applicable SILs. The threshold levels and dispersion modeling analyses supporting those levels are presented in the *State of Idaho Guideline for Performing Air Quality Impact Analyses*[1] (*Idaho Air Modeling Guideline*). Use of a modeling threshold represents the use of conservative air impact modeling, performed in support of the threshold, as a project SIL analysis. Project-specific modeling applicability for this project is addressed in Section 3.1.1 of this memorandum.

A cumulative NAAQS impact analysis for attainment area pollutants involves assessing ambient impacts (typically the design values consistent with the form of the standard) from facility-wide emissions, and emissions from any nearby co-contributing sources, and then adding a DEQ-approved background concentration value to the modeled result that is appropriate for the criteria pollutant/averaging-period at the facility location and the area of significant impact. The resulting pollutant concentrations in ambient air are then compared to the NAAQS listed in Table 2. Table 2 also lists SILs and specifies the modeled design value that must be used for comparison to the NAAQS. NAAQS compliance is evaluated on a receptor-by-receptor basis for the modeling domain.

If the cumulative NAAQS impact analysis indicates a violation of the standard, the permit may not be issued if the proposed project has a significant contribution (exceeding the SIL) to the modeled violation. This evaluation is made specific to both time and space. If the SIL analysis indicates the facility/modification has an impact exceeding the SIL, the facility might not have a significant contribution to a violation if impacts are below the SIL at the specific receptor showing the violation during the time periods when a modeled violation occurred.

Table 2. APPLICABLE REGULATORY LIMITS				
Pollutant	**Averaging Period**	**Significant Impact Levels[a] ($\mu g/m^3$)[b]**	**Regulatory Limit[c] ($\mu g/m^3$)**	**Modeled Design Value Used[d]**
PM_{10}[e]	24-hour	5.0	150[f]	Maximum 6th highest[g]
$PM_{2.5}$[h]	24-hour	1.2	35[i]	Mean of maximum 8th highest[j]
	Annual	0.3	12[k]	Mean of maximum 1st highest[l]
Carbon monoxide (CO)	1-hour	2,000	40,000[m]	Maximum 2nd highest[n]
	8-hour	500	10,000[m]	Maximum 2nd highest[n]
Sulfur Dioxide (SO_2)	1-hour	3 ppb[o] (7.8 $\mu g/m^3$)	75 ppb[p] (196 $\mu g/m^3$)	Mean of maximum 4th highest[q]
	3-hour	25	1,300[m]	Maximum 2nd highest[n]
	24-hour	5	365[m]	Maximum 2nd highest[n]
	Annual	1.0	80[r]	Maximum 1st highest[n]
Nitrogen Dioxide (NO_2)	1-hour	4 ppb (7.5 $\mu g/m^3$)	100 ppb[s] (188 $\mu g/m^3$)	Mean of maximum 8th highest[t]
	Annual	1.0	100[r]	Maximum 1st highest[n]
Lead (Pb)	3-month[u]	NA	0.15[r]	Maximum 1st highest[n]
	Quarterly	NA	1.5[r]	Maximum 1st highest[n]
Ozone (O_3)	8-hour	40 TPY VOC[v]	75 ppb[w]	Not typically modeled

a. Idaho Air Rules Section 006 (definition for significant contribution) or as incorporated by reference as per Idaho Air Rules Section 107.03.b.
b. Micrograms per cubic meter.
c. Incorporated into Idaho Air Rules by reference, as per Idaho Air Rules Section 107.
d. The maximum 1st highest modeled value is always used for the significant impact analysis unless indicated otherwise. Modeled design values are calculated for each ambient air receptor.
e. Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers.
f. Not to be exceeded more than once per year on average over 3 years.
g. Concentration at any modeled receptor when using five years of meteorological data.
h. Particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers.
i. 3-year mean of the upper 98th percentile of the annual distribution of 24-hour concentrations.
j. 5-year mean of the 8th highest modeled 24-hour concentrations at the modeled receptor for each year of meteorological data modeled. For the SIL analysis, the 5-year mean of the 1st highest modeled 24-hour impacts at the modeled receptor for each year.
k. 3-year mean of annual concentration.
l. 5-year mean of annual averages at the modeled receptor.
m. Not to be exceeded more than once per year.
n. Concentration at any modeled receptor.
o. Interim SIL established by EPA policy memorandum.
p. 3-year mean of the upper 99th percentile of the annual distribution of maximum daily 1-hour concentrations.
q. 5-year mean of the 4th highest daily 1-hour maximum modeled concentrations for each year of meteorological data modeled. For the significant impact analysis, the 5-year mean of 1st highest modeled 1-hour impacts for each year is used.
r. Not to be exceeded in any calendar year.
s. 3-year mean of the upper 98th percentile of the annual distribution of maximum daily 1-hour concentrations.
t. 5-year mean of the 8th highest daily 1-hour maximum modeled concentrations for each year of meteorological data modeled. For the significant impact analysis, the 5-year mean of maximum modeled 1-hour impacts for each year is used.
u. 3-month rolling average.
v. An annual emissions rate of 40 ton/year of VOCs is considered significant for O_3.
w. Annual 4th highest daily maximum 8-hour concentration averaged over three years. The O_3 standard was revised (the notice was signed by the EPA Administrator on October 1, 2015) to 70 ppb. However, this standard will not be applicable for permitting purposes until it is incorporated by reference *sine die* into Idaho Air Rules.

Compliance with Idaho Air Rules Section 203.02 is generally demonstrated if: a) all modeled impacts of the SIL analysis are below the applicable SIL or other level determined to be inconsequential to NAAQS compliance; or b) modeled design values of the cumulative NAAQS impact analysis (modeling all emissions from the facility and co-contributing sources, and adding a background concentration) are less than

applicable NAAQS at receptors where impacts from the proposed facility/modification exceeded the SIL or other identified level of consequence; or c) if the cumulative NAAQS analysis showed NAAQS violations, the impact of proposed facility/modification to any modeled violation was inconsequential (typically assumed to be less than the established SIL) for that specific receptor and for the specific modeled time when the violation occurred.

2.5 Toxic Air Pollutant Analyses

Emissions of toxic substances are generally addressed by Idaho Air Rules Section 161:

> *Any contaminant which is by its nature toxic to human or animal life or vegetation shall not be emitted in such quantities or concentrations as to alone, or in combination with other contaminants, injure or unreasonably affect human or animal life or vegetation.*

Permitting requirements for toxic air pollutants (TAPs) from new or modified sources are specifically addressed by Idaho Air Rules Section 203.03 and require the applicant to demonstrate to the satisfaction of DEQ the following:

> *Using the methods provided in Section 210, the emissions of toxic air pollutants from the stationary source or modification would not injure or unreasonably affect human or animal life or vegetation as required by Section 161. Compliance with all applicable toxic air pollutant carcinogenic increments and toxic air pollutant non-carcinogenic increments will also demonstrate preconstruction compliance with Section 161 with regards to the pollutants listed in Sections 585 and 586.*

Per Idaho Air Rules Section 210, if the total project-wide emissions increase of any TAP associated with a new source or modification exceeds screening emission levels (ELs) of Idaho Air Rules Section 585 or 586, then the ambient impact of the emissions increase must be estimated. If ambient impacts are less than applicable Acceptable Ambient Concentrations (AACs) for non-carcinogens of Idaho Air Rules Section 585 and Acceptable Ambient Concentrations for Carcinogens (AACCs) of Idaho Air Rules Section 586, then compliance with TAP requirements has been demonstrated.

Idaho Air Rules Section 210.20 states that if TAP emissions from a specific source are regulated by the Department or EPA under 40 CFR 60, 61, or 63, then a TAP impact analysis under Section 210 is not required for that TAP.

3.0 Analytical Methods and Data

This section describes the methods and data used in analyses to demonstrate compliance with applicable air quality impact requirements.

3.1 Emission Source Data

Emissions rates of criteria pollutants and TAPs for the project were provided by the applicant for various applicable averaging periods. Review and approval of estimated emissions was the responsibility of the

DEQ permit writer and is not addressed in this modeling memorandum. DEQ modeling review included verification that the application's potential emissions rates were properly used in the model. The rates listed must represent the maximum allowable rate as averaged over the specified period.

Emissions rates used in the dispersion modeling analyses submitted by TASCO should be reviewed by the DEQ permit writer against those in the emissions inventory of the permit application. All modeled criteria air pollutant and TAP emissions rates should be equal to or greater than the facility's emissions calculated in other sections of the PTC application or requested permit allowable emission rates.

3.1.1 Criteria Pollutant Emissions Rates and Modeling Applicability

If facility-wide potential to emit (PTE) values, or project wide PTE in some instances, for a specific criteria pollutants would qualify for a below regulatory concern (BRC) permit exemption as per Idaho Air Rules Section 221 if it were not for some pollutants exceeding BRC thresholds, then an air impact analysis for that pollutant may not be required for permit issuance. DEQ's regulatory interpretation policy of exemption provisions of Idaho Air Rules (Policy on NAAQS Compliance Demonstration Requirements, DEQ policy memorandum, July 11, 2014) is that: "A DEQ NAAQS compliance assertion will not be made by the DEQ modeling group for specific criteria pollutants having a project emissions increase below BRC levels, provided the proposed project would have qualified for a Category I Exemption for BRC emissions quantities except for the emissions of another criteria pollutant." The interpretation policy also states that the exemption criteria of uncontrolled PTE not to exceed 100 ton/year (Idaho Air Rules Section 220.01.a.i) is not applicable when evaluating whether a NAAQS impact analyses is required. A permit will be issued limiting PTE below 100 ton/year, thereby negating the need to maintain calculated uncontrolled PTE under 100 ton/year.

DEQ has generated non-site-specific project modeling thresholds for those projects that cannot use the BRC exemption from an impact analysis (if there are specific permitted emissions limits that require changing, etc.). Modeling applicability thresholds are provided in the *Idaho Air Modeling Guideline*. These thresholds were based on assuring an ambient impact of less than established SIL for that specific pollutant and averaging period.

If project-specific total emissions rates are below Level I Modeling Thresholds, project-specific air impact analyses are not necessary for permitting. Use of level II modeling thresholds are conditional, requiring DEQ approval. Table 3 provides the emissions-based modeling applicability summary. As mentioned, TASCO compared emission estimates with Level I Modeling Thresholds, and determined that modeling is necessary for the criteria pollutants listed in Table 3. Emissions as modeled per source in the final application submitted on September, 2016, are listed in Table 4.

An impact analysis must be performed for pollutant increases that would not qualify for the BRC exemption from an impact analysis. Emissions of $PM_{2.5}$ and NOx from the proposed project exceeded BRC thresholds, thereby requiring a NAAQS compliance demonstration for permit issuance. TASCO compared project emissions with Level 1 modeling thresholds for all criteria pollutants. Utilizing annual operating factors as contained in the permit, the annual emissions for $PM_{2.5}$ and NO_x are above the Level 1 modeling thresholds, and ~~so~~ modeling was therefore required for these pollutants.

Table 3. MODELING APPLICABILITY ANALYSIS RESULTS						
Pollutant	**Averaging Period**	**Emissions**	**BRC Threshold (ton/year)**	**Level I Modeling Thresholds (lb/hour or ton/year)**	**Level II Modeling Thresholds (lb/hour or ton/year)**	**Modeling Required**
$PM_{2.5}$	Annual	1.81 ton/yr	1	0.350	4.1	Yes
	24-hour	0.0 lb/hr		0.054	0.63	No
PM_{10}	24-hour	0.0 lb/hr	1.5 (0.34 lb/hr)	0.22	2.6	No
NOx	Annual	39.39 ton/yr	4	1.2	14	Yes
	1-hour	0.000 lb/hr		0.2	2.4	No
SO_2	Annual	0.15 ton/yr	4	1.2	14	No
	1-hour	0.0 lb/hr		0.21	2.5	No
CO	Annual	12.41 ton/yr	10	15	175	No

Ozone (O_3) differs from other criteria pollutants in that it is not typically emitted directly into the atmosphere. O_3 is formed in the atmosphere through reactions of VOCs, NOx, and sunlight. Atmospheric dispersion models used in stationary source air permitting analyses (see Section 3.3.3) cannot be used to estimate O_3 impacts resulting from VOC and NOx emissions from an industrial facility. O_3 concentrations resulting from area-wide emissions are predicted by using more complex airshed models such as the Community Multi-Scale Air Quality (CMAQ) modeling system. Use of the CMAQ model is very resource intensive and DEQ asserts that performing a CMAQ analysis for a particular permit application is not typically a reasonable or necessary requirement for air quality permitting.

Addressing secondary formation of O_3 has been somewhat addressed in EPA regulation and policy. As stated in a letter from Gina McCarthy of EPA to Robert Ukeiley, acting on behalf of the Sierra Club (letter from Gina McCarthy, Assistant Administrator, United States Environmental Protection Agency, to Robert Ukeiley, January 4, 2012):

> *. . . footnote 1 to sections 51.166(I)(5)(I) of the EPA's regulations says the following: "No de minimis air quality level is provided for ozone. However, any net emission increase of 100 tons per year or more of volatile organic compounds or nitrogen oxides subject to PSD would be required to perform an ambient impact analysis, including the gathering of air quality data."*
>
> *The EPA believes it unlikely a source emitting below these levels would contribute to such a violation of the 8-hour ozone NAAQS, but consultation with an EPA Regional Office should still be conducted in accordance with section 5.2.1.c. of Appendix W when reviewing an application for sources with emissions of these ozone precursors below 100 TPY."*

Allowable emissions estimates of VOCs and NOx are below the 100 tons/year threshold, and DEQ determined it was not appropriate or necessary to require a quantitative source specific O_3 impact analysis.

Table 4 provides criteria pollutant emissions rates used in the air impact analyses. The short-term rates have been normalized over an annual period containing 8160 hours of operation. The annualized hours of

operation per month as used in the modeling are listed in Table 5.0

Table 4. MODELED EMISSION RATES FOR CRITERIA POLLUTANTS					
Source ID	**Source Description**	**$PM_{2.5}$ Annual (tpy)[a]**	**NO_2 Annual (tpy)[a]**	**$PM_{2.5}$ Annual (lbs/hr)[b]**	**NO_2 Annual (lbs/hr)[b]**
PB1A	B & W Boiler	0.78	10.81	0.19	2.65
PB2A	Erie City Boiler	1.03	28.58	0.25	7.00

[a] tons/year.
[b] pounds/hour, annualized rate.

Table 5. ANNUALIZED FACTORS FOR MONTHLY HOURS OF OPERATION				
Seasonality	**B&W Boiler**		**Erie City Boiler**	
Month	**factor**	**hours/month**	**factor**	**hours/month**
January	1	744	1	744
February	1	672	1	672
March	1	744	1	744
April	1	720	1	720
May	1	744	1	744
June	1	720	1	720
July	0.2	144	0.2	144
August	1	744	1	744
September	1	720	1	720
October	1	744	1	744
November	1	720	1	720
December	1	744	1	744
Total	8160	hrs/year	8160	hrs/year

Secondary Particulate Formation

The impact from secondary particulate formation resulting from emissions of NOx, SO_2, and/or VOCs was assumed by DEQ to be negligible based on the magnitude of emissions and the short distance from emissions sources to modeled receptors where maximum PM_{10} and $PM_{2.5}$ impacts would be anticipated.

3.1.2 Toxic Air Pollutant Emissions Rates

TAP emissions regulations under Idaho Air Rules Section 220 are only applicable for new or modified sources constructed after July 1, 1995. The submitted emissions inventory in the application identified three TAPs having potential emissions increases that could exceed screening emissions levels (ELs) of Idaho Air Rules Section 585 and 586. Potential increases in emissions of other TAPs were all less than applicable ELs. Detailed calculations of estimated TAP emissions are included in the permit application. Daily increases are based on a 2,000 ton per day slice increase. Short-term ammonia emissions are treated as occurring primarily

from the main mill vents. Sources with ammonia emissions include the carbonation tanks, the precipitated calcium carbonate (PCC) filter vent, evaporator vents, the process slaker, cooling towers, and lagoons. Long term aldehyde emissions (acetaldehyde and formaldehyde) are emitted from the carbonation tanks and evaporator vents. Table 6 lists emission increases for theses TAPs and compares them to the EL.

Table 6. PROJECT TOTAL TAP EMISSIONS RATES

Pollutant	CAS No.	Total Emissions Increase (lbs/hr)[a]	EL (lbs/hr)[a]
Ammonia	7664-41-7	53.5	1.20E-00
Acetaldehyde	75-07-0	9.99E-02	3.00E-03
Formaldehyde	50-00-0	9.18E-04	5.10E-04

[a.] Pounds/hour.

Table 7 provides source-specific TAP emission rates used in the air impact analyses.

Table 7. TAPS EMISSIONS AS MODELED BY SOURCE

Source ID	Source Description	Acetaldehyde (lb/hr)[a]	Formaldehyde (lb/hr)[a]	Ammonia (lb/hr)[a]
PK2	Process Slaker	0	0	1.486
EVAP	Evaporator Vent	9.99E-04	1.84E-05	4.458
PC1	Cooling Tower Vent #1	0	0	2.336
PC2	Cooling Tower Vent #2	0	0	2.336
PC3	Cooling Tower Vent #3	0	0	2.571
PC4	Cooling Tower Vent #4	0	0	2.571
PC5	Cooling Tower Vent #5	0	0	6.833
PC6	Cooling Tower Vent #6	0	0	6.833
PC7	Cooling Tower Vent #7	0	0	1.397
PC8	Cooling Tower Vent #8	0	0	1.397
PK1/2A	1st Carbonation Tank	0.039	4.22E-04	5.944
PK1/2B	2nd Carbonation Tank	0.06	4.78E-04	5.944
PF1	PCC Vent	0	0	5.944
OSL	Off Site Lagoon	0	0	3.449

[a] Pounds/hour.

3.1.3 Emission Release Parameters

Table 8 provides emissions release parameters, including stack height, stack diameter, exhaust temperature, and exhaust velocity for facility sources as used in the final modeling assessment.

Stack parameters used in the modeling analyses were adequately documented/justified in the application. Stack exhaust parameters for the two large boilers were assigned "calculated" values, less than (conservative) those taken from recent stack tests. Sources with capped or horizontal flows were assigned an exit velocity of 0.001 m/s.

TABLE 8. MODELING SOURCE PARAMETERS								
Point Sources								
Source ID	**Source Description**	**Easting (X)[a] (m)**	**Northing (Y)[b] (m)**	**Base Elevation (m)**	**Stack Height (ft)[c]**	**Temp (°F)[d]**	**Exit Velocity (fps)[e]**	**Stack Diameter (ft)**
PK2	Process Slaker	274084	4721257	1264.3	52.0	153.7	7.400	3.3
EVAP	Evaporator Vent	273791	4721293	1264.1	40.9	203.0	56.900	1.3
PB1A	B & W Boiler	273810	4721206	1264.5	70.0	312.0	45.064	6.0
PB2A	Erie City Boiler	273819	4721201	1264.5	70.0	387.0	50.618	6.0
PC1	Cooling Tower Vent #1	273881	4721208	1265.3	51.0	78.5	28.700	14.0
PC2	Cooling Tower Vent #2	273881	4721201	1265.3	51.0	78.5	28.700	14.0
PC3	Cooling Tower Vent #3	273880	4721187	1265.3	48.0	78.5	21.500	17.0
PC4	Cooling Tower Vent #4	273880	4721180	1265.1	48.0	78.5	21.500	17.0
PC5	Cooling Tower Vent #5	273889	4721138	1265.3	73.0	78.5	19.600	29.0
PC6	Cooling Tower Vent #6	273888	4721126	1265.3	73.0	78.5	19.600	29.0
PC7	Cooling Tower Vent #7	273770	4721469	1263.8	16.4	78.5	55.900	10.0
PC8	Cooling Tower Vent #8	273776	4721469	1263.8	16.4	78.5	55.900	10.0
PK1/2A	1st Carbonation Tank	273812	4721330	1264.6	79.0	180.0	36.433	3.5
PK1/2B	2nd Carbonation Tank	273800	4721295	1264.4	66.0	179.0	6.933	3.5
PK3	Process Slaker	273861	4721311	1265.0	20.6	124.0	0.003	0.4
PF1	PCC Vent	273848	4721281	1264.8	79.5	176.0	0.170	2.5
Area Sources								
Source ID	**Source Description**	**Easting (X) (m)**	**Northing (Y) (m)**	**Release Ht (ft)**	**Length (E) (ft)**	**Length (N) (ft)**	**Angle from North (degrees)**	**Initial Vert. Dim (ft)**
OSP	Off Site Lagoon	273543	4721493	15	370	165	11	5

a. Universal Transverse Mercator coordinates in meters (m) in the east/west direction.
b. Universal Transverse Mercator coordinates in meters in the north/south direction.
c. Feet.
d. Degrees Fahrenheit.
e. Feet per second.

3.2 Background Concentrations

Background concentrations were not necessary for this analysis as all maximum predicted modeled concentrations for all criteria pollutants were below significant impact levels (SILs).

3.3 Impact Modeling Methodology

This section describes the modeling methods used by the applicant to demonstrate preconstruction

compliance with applicable air quality standards.

3.3.1 General Overview of Analyses

TASCO and Stantec performed project-specific air impact analyses that were determined by DEQ to be reasonably representative of the proposed facility as described in the application. Results of the submitted analyses demonstrate compliance with applicable air quality standards to DEQ's satisfaction, provided the facility is operated as described in the submitted application and in this memorandum.

Table 9 provides a brief description of parameters used in the modeling analyses.

Table 9. MODELING PARAMETERS

Parameter	Description/Values	Documentation/Addition Description
General Facility Location	Paul, Idaho	The facility is located in an area that is attainment or unclassified for all criteria air pollutants
Model	AERMOD	AERMOD with the PRIME downwash algorithm, version 15181.
Meteorological Data	2000-2004 INL/Minidoka, Idaho surface data, and upper air data from Boise, ID	The meteorological model input files for this project were provided by and recommended as most representative for this project by IDEQ, as described in the IDEQ modeling protocol and verified by IDEQ's approval of that protocol.
Terrain	Considered	See section 5.3 below
Building Downwash	Considered	Because there are substantial buildings at the facility, BPIP-PRIME was used to evaluate building dimensions for consideration of downwash effects in AERMOD.
Receptor Grid	Grid 1	25-meter spacing along the ambient air boundary and in areas of high impacts to distances of 1000 meters from the boundary
	Grid 2	50-meter spacing in areas of public access and out to distances of 2000+ meters with respect to the facility
	Grid 3	200-meter spacing out to approximately 10,000 meters

3.3.2 Modeling protocol and Methodology

As mentioned in Section 1, a modeling protocol was not submitted for this project. A permit application was submitted on March 23, 2016. This application was determined to be incomplete on April 6, 2016, largely due to missing forms and failure to use DEQ's modeling report template. TASCO responded with a revised application on April 13 and April 14, 2016. DEQ initially deemed the application complete on May 13, 2016. After further review, DEQ requested revisions to the project emissions inventory for the natural gas boilers. This was required to reflect condition 2.15 of the April 2014 PTC, where the applicant has been directed to not use emission decreases associated with the removal of coal usage at the facility for creditable decreases in future permitting actions. DEQ also requested that TASCO provide modeling of the natural gas fired boilers to account for the increase in projected annual emissions for criteria pollutants that would be greater than Level I modeling thresholds. Because of the large beet crop and limited time span between the application and permit issuance, TASCO advised DEQ that their existing beet throughput limit might be exceeded before September 8, 2016. DEQ then issued a consent order allowing TASCO to continue operations provided they commit to the conditions of the consent order. One of these conditions required

TASCO to provide an air impact analysis demonstrating that the above mentioned requested increase in emissions would not cause or significantly contribute to a violation of the NAAQS or exceed a TAP AAC/AACC. TASCO responded with a revised air impact modeling analysis on July 18, 2016. DEQ found minor errors in the modeling files and requested that TASCO submit revised modeling analyses, correcting these errors. TASCO responded with a resubmitted application on July 26, 2016. DEQ determined that some errors were still evident in the files. These consisted of errors in the monthly utilization factors and correlating emission rates used for annual NO_2 and $PM_{2.5}$ modeling. DEQ corrected these inputs and reran the modeling assessment in a sensitivity analysis to provide accurate results. Compliance with the NAAQS was adequately demonstrated, and the consent order was signed on July 27, 2016.

On September 26, 2016, TASCO (and Stantec) submitted an addendum to the application, in accordance with the consent order agreement. In this addendum, TASCO provided revised emission rates, based on refined estimates of boiler emissions from periods of only natural gas usage. There were inconsistencies between the emissions used in the model input files and the PTE emissions listed in the application. In particular, the boiler operational days, stated as 340 days was slightly underestimated in the modeling files. Because of the emission differences caused by the error in the operational days, a final revision of the impact analyses was submitted on November 14. In this revision, the days of boiler operation used in the model needed to provide power to adequately account for the requested 10% increase in beet production (the modified throughput limit in the permit), was set to 340 days of operation.

Project-specific modeling and other required impact analyses were generally conducted using data and methods discussed in pre-application correspondence and in the *Idaho Air Quality Modeling Guideline*[1].

3.3.3 Model Selection

Idaho Air Rules Section 202.02 requires that estimates of ambient concentrations be based on air quality models specified in 40 CFR 51, Appendix W (Guideline on Air Quality Models). The refined, steady state, multiple source Gaussian dispersion model AERMOD was promulgated as the replacement model for ISCST3 in December 2005. AERMOD retains the single straight line trajectory of ISCST3, but includes more advanced algorithms to assess turbulent mixing processes in the planetary boundary layer for both convective and stable stratified layers.

AERMOD version 15181 was used by the applicant for the air impact modeling analyses to evaluate impacts of the facility. This version is the current version at the time the application was received by DEQ.

3.3.4 Meteorological Data

TASCO used meteorological data previously utilized for projects at this facility. This data was collected at an INL monitoring location in Minidoka/Burley # 25867 for the period 2000-2004. Upper air data was collected from the Boise, Idaho airport. DEQ determined the data as used in the submitted analyses is representative for modeling in the locale of TASCO Paul.

3.3.5 Effects of Terrain on Modeled Impacts

Terrain data were extracted from United States Geological Survey (USGS) National Elevation Dataset (NED) files in the WGS84 datum (approximately equal to the NAD83 datum). NWRC used 1 Arc Second resolution data, which is adequate for this analysis.

The terrain preprocessor AERMAP Version 11103 was used to extract the elevations from the NED files and assign them to receptors in the modeling domain in a format usable by AERMOD. AERMAP also

determined the hill-height scale for each receptor. The hill-height scale is an elevation value based on the surrounding terrain which has the greatest effect on that individual receptor. AERMOD uses those heights to evaluate whether the emissions plume has sufficient energy to travel up and over the terrain or if the plume will travel around the terrain.

DEQ reviewed the area surrounding the facility by using the web-based mapping program Google Earth, which uses the WGS84 datum. DEQ also overlaid modeling files with a digital photograph background images acquired from the 2013 ARCGIS NAIP (National Agriculture Imagery Program) data base. The immediate area is effectively flat with regard to dispersion modeling affects. Elevations in the modeling domain matched those indicated by the background images

3.3.6 Facility Layout

DEQ compared the facility layout used in the model to that indicated in aerial photographs on Google Earth. The modeled layout was consistent with aerial photographs in Google Earth as well as from those in the ARCGIS 2013 NAIP database.

3.3.7 Effects of Building Downwash on Modeled Impacts

Potential downwash effects on emissions plumes are usually accounted for in the model by using building dimensions and locations (locations of building corners, base elevation, and building heights). Dimensions and orientation of proposed buildings were needed as input to the Building Profile Input Program for the Plume Rise Model Enhancements downwash algorithm (BPIP-PRIME) because there are existing structures affecting the emissions plumes at the facility.

3.3.8 Ambient Air Boundary

Ambient air is defined in Section 006 of the Idaho Air Rules as "that portion of the atmosphere, external to buildings, to which the general public has access." Public access to the TASCO facility is precluded through management and physical barriers, including chain linked fencing. Because roads and a rail line transect the property in several locations, discrete modeling receptors have been placed along the center line of these access ways.

3.3.9 Receptor Network

Table ~~8~~ 9 describes the receptor grid used in the submitted analyses. The receptor grid met the minimum recommendations specified in the *Idaho Air Quality Modeling Guideline*[1]. DEQ determined this grid assured maximum impacts were reasonably resolved by the model considering: 1) types of sources modeled; 2) modeled impacts and the modeled concentration gradient; 3) conservatism of the methods and data used as inputs to the analyses; 4) potential for continual exposures or exposure to sensitive receptors. Additionally, DEQ performed sensitivity analyses using a finer grid spaced receptor network to assure that maximum concentrations were below all applicable standards.

3.3.10 Good Engineering Practice Stack Height

An allowable good engineering practice (GEP) stack height may be established using the following equation in accordance with Idaho Air Rules Section 512.03.b:

H = S + 1.5L, where:

H = good engineering practice stack height measured from the ground-level elevation at the base of the stack.

S = height of the nearby structure(s) measured from the ground-level elevation at the base of the stack.

L = lesser dimension, height or projected width, of the nearby structure.

Buildings exist in the vicinity for all point sources modeled. Therefore, consideration of downwash caused by nearby buildings was required.

4.0 Impact Modeling Results

4.1 Results for NAAQS Significant Impact Level Analyses

TASCO performed air quality modeling for those criteria pollutants having emissions exceeding Level I modeling thresholds ($PM_{2.5}$ and NO_2). The results from the Significant Impact Level (SIL) Analyses for these pollutants are listed in Table 10 and show maximum predicted impacts are below the SILs. Therefore, compliance with all NAAQS has been demonstrated.

TABLE 10. Significant Impact Level Modeling Results

Pollutant	Averaging Period	Maximum Modeled Concentration ($\mu g/m^3$)[a]	Significant Impact Level ($\mu g/m^3$)[a]	% of SIL[b]
$PM_{2.5}$	Annual	0.04	0.30	13
NO_2	Annual	0.68	1.0	68

a. Micrograms per cubic meter.
b. Significant Impact Level.

4.2 Results for TAPs Impact Analyses

Dispersion modeling is required to demonstrate compliance with TAP increments specified by Idaho Air Rules Section 585 and 586 for those TAPs with project-specific emission increases exceeding emissions screening levels (ELs). Because there are several TAPs emissions that exceed the ELs, modeling analyses were needed to demonstrate compliance with ~~all~~ those AACs and AAACs. Results are listed in Table 11 and show compliance with all AAC and AAAC.

Table 11. TAP MODELING RESULTS

Pollutant	CAS No.	Average	Modeled Conc. ($\mu g/m^3$)[a]	AAC/AAAC[b] ($\mu g/m^3$)	%AAC/AAAC

Ammonia	7664-41-7	24-hour	136.14[c]	900	15%
Acetaldehyde	75-07-0	Annual	0.0150[c]	0.45	3%
Formaldehyde	50-00-0	Annual	1.3E-04[c]	7.70E-02	<1%

a. Micrograms per cubic meter.
b. Acceptable Ambient Concentration or Acceptable Ambient Concentration of a Carcinogen.
c. Maximum average concentration for five-year period 2008-2012.

5.0 Conclusions

The ambient air impact analyses and other air quality analyses submitted with the PTC application demonstrated to DEQ's satisfaction that emissions from the TASCO-Paul project will not cause or significantly contribute to a violation of any ambient air quality standard.

References:

1. *State of Idaho Guideline for Performing Air Quality Impact Analyses.* Idaho Department of Environmental Quality. September 2013. State of Idaho DEQ Air Doc. ID AQ-011. Available at http://www.deq.idaho.gov/media/1029/modeling-guideline.pdf.

2. Air Quality Environmental Science and Technology Consortium (NW AIRQUEST). *Lookup 2009-2011 Design Values of Criteria Pollutants*. Available at: http://lar.wsu.edu/nw-airquest/lookup.html.

Hours of Operation

Seasonality	B&W Boiler		Erie City Boiler	
Month	factor	hrs/mo	factor	hrs/mo
January	1.0	744	1.0	744
February	1.0	672	1.0	672
March	1.0	744	1.0	744
April	1.0	720	1.0	720
May	1.0	744	1.0	744
June	1.0	720	1.0	720
July	0.2	144	0.2	144
August	1.0	744	1.0	744
September	1.0	720	1.0	720
October	1.0	744	1.0	744
November	1.0	720	1.0	720
December	1.0	744	1.0	744
Total	8160	hrs/y	8160	hrs/y

Annualized Emissions (lbs/h)

Boilers	$PM_{2.5}$	NOx	SO_2	CO	VOC
B&W Boiler	0.19	2.65	NA	NA	NA
Erie City Boiler	0.25	7.00	NA	NA	NA
Total	0.44	9.65	NA	NA	NA

APPENDIX C – FACILITY DRAFT COMMENTS

The following comments were received from the facility on January 20, 2017:

Facility Comment: Condition 2.3 - During the January 9, 2017 meeting with TASCO and IDEQ representatives, TASCO requested to further increase the annual beet slice limitation. TASCO proposed in the March 2016 PTC Application and the August 2016 Consent Order to increase the annual throughput to 3,700,000 tons per campaign year. Since that time, TASCO received new information about increasing crop yields and the associated estimated production throughput for future campaigns. TASCO requests an annual throughput of 3,852,000 tons per campaign year to allow for increased production that is anticipated from larger beet crops in Idaho. Updated emissions estimates for the mill vents are provided in Attachment #1.

As shown, a 352,000 ton slice increase to 3,852,000 tons results in a main mill VOC increase of 13.3 tons per year. For the original request of 200,000 tons slice to 3,700,000 tons, the estimated VOC increase was 7.6 tons/year. The higher annual slice increase is not significant and continues to be a minor modification consistent with the original request.

Attachment #1 also provides updated acetaldehyde and formaldehyde TAP's estimates for a slice increase to 3,800,000 tons. The table below provides a comparison of original and new TAP's estimates and predicted ambient impacts.

Aldehyde Emissions Estimates & Predicted Modeled Impacts

Slice Increase	Acetaldehyde			Formaldehyde		
(tons)	Rate (lbs/h)	Predicted (ug/m^3)[a]	AAAC (ug/m^3)[b]	Rate (lbs/h)	Predicted (ug/m^3)[a]	AAAC (ug/m^3)[b]
200,000	9.99E-2	0.0150	0.45	9.18E-4	1.3E-4	7.7E-2
352,000	1.76E-1	0.0264[c]	0.45	1.62E-3	2.29E-4[c]	7.7E-2

a Micrograms per cubic meter
b Acceptable ambient concentration of a carcinogen
c Estimated by multiplying the predicted impacts at 200,000 tons by 1.76

Estimated aldehyde ambient impacts for a 352,000 tons slice increase continue to only be a fraction of the acetaldehyde and formaldehyde AAAC's.

DEQ Response: The requested beet slice increase has been changed in the PTC. Emission increases have been incorporated into the tables in the Statement of Basis and the modeling group has reviewed the requested change.

Facility Comment: Conditions 2.5 & 2.6 - Conditions 2.5 and 2.6 were included in the August 13, 2014 PTC and applies to boiler coal firing thru the calendar year 2016. Since the boilers no longer fire coal then as described by DEQ in the draft SOB (pg. 17), Conditions 2.5 and 2.6 are obsolete and should be deleted.

DEQ Response: The requested change has been made because the boilers no longer fire coal and the monitoring was required only through calendar year 2016.

Facility Comment: Condition 3.3 Emissions Limits (Table 3.2) - The underlying PTC issued August 13, 2014 did not include emissions limits. Short-term boiler emissions changes are not expected to change as a result of this project and were not required to be addressed in the Minor PTC Modification request and PTC application. Therefore, the short-term emissions should be deleted from Table 3.2.

For long-term emissions, TASCO recommends that Table 3.2 include a combined limit for all boilers. This would allow for additional operational flexibility of the individual boilers including the Nebraska backup boiler. In addition, TASCO revised the footnote defining tons per year for this table to correspond to the reference in the SOB, Table 2 footnote (d).

The combined emissions from the Boilers (B&W, Erie City, Nebraska) shall not exceed any corresponding emissions rate limits listed in Table 3.2.

Table 3.2 Boiler Emission Limits[a]

Source Description	PM_{10}[b] T/yr[c]	SO_2[b] T/yr[c]	NO_x[b] T/yr[c]	CO[b] T/yr[c]	VOC[b] T/yr[c]
Boilers	11.89	1.00	266.97	128.33	8.70

a In absence of any other credible evidence, compliance is ensured by complying with permit operating, monitoring, and record keeping requirements.

b Particulate matter with an aerodynamic diameter less than or equal to a nominal ten (10) micrometers, including condensable particulate as defined in IDAPA 58.01.01.006.

c Tons per campaign year, as defined in Condition 2.1.d B&W, Erie City and Nebraska

DEQ Response: The hourly emission rates for the boilers have been removed from the PTC because short-term boiler emission rates did not change as a result of this permitting action. Footnote (c) was revised to reflect the ton per year limit as defined as tons per campaign year in Permit Condition 2.1.

The annual emission limits will remain for the individual boilers. Compliance with a combined limit has not been demonstrated through an ambient analysis or through a PSD analysis that a combined emission limit would not cause a violation.

Facility Comment: Condition 3.7 - TASCO proposes to monitor and record the amount of fuel being used in therms per month and summing the monthly totals for the campaign to demonstrate compliance with Condition 3.6. Data regarding hours of operation is not needed to demonstrate compliance. TASCO suggests the following revision to Condition 3.7:

Condition 3.7 Boiler Operation Recordkeeping (B&W, Erie City, Nebraska)

The permittee shall monitor and record the combined amount of fuel used in the boilers (B&W, Erie City, Nebraska) in therms per month and summing the monthly totals for the campaign to demonstrate compliance with Condition 3.6.

DEQ Response: Permit Condition 3.7 has been revised to remove the hours of operation recordkeeping. Recordkeeping for the amount of fuel used is sufficient to demonstrate compliance with the operating limits for the B&W and Erie City boilers. The Nebraska Boiler is permitted under a separate PTC.

Facility Comment: Conditions 3.8 & 3.9 – These previous Boiler MACT requirements have been completed.

DEQ Response: Permit Conditions 3.8 and 3.9 are meant to demonstrate continuous compliance with Boiler MACT requirements even though the initial dates for compliance have passed. The facility still has to comply with all Boiler MACT applicable requirements.

Facility Comment: Pg. 13 of Statement of Basis - NSPS Applicability (40 CFR 60) - The Nebraska boiler which was installed at the facility in 2005 is subject to 40 CFR 60 Db requirements.

DEQ Response: The requested change has been made.

Facility Comment: Pg. 13 of Statement of Basis - MACT Applicability (40 CFR 63) - The Nebraska boiler is also subject to "Boiler MACT" requirements.

DEQ Response: The requested change has been made.

Facility Comment: Pg. 17 of Statement of Basis - Conditions 2.5 & 2.6 - As stated in the draft SOB, it is recommended that these conditions be removed from the draft PTC (see Draft PTC comments above).

DEQ Response: The requested change has been made.

Facility Comment: Pg. 17 of Statement of Basis - New Permit Condition 3.3 - As stated in the draft SOB, the purpose of emissions limits in Condition 3.3 are for PSD avoidance. As a result, this permit condition should only include annual emissions limits (see Draft PTC comments above).

DEQ Response: The requested change has been made.

APPENDIX D – PROCESSING FEE

PTC Prcessing Fee Calculation Worksheet

Instructions:
Fill in the following information and answer the following questions with a Y or N. Enter the emissions increases and decreases for each pollutant in the table.

Company: The Amalgamated Sugar Company
Address: 50 South 500 West
City: Paul
State: ID
Zip Code: 83347
Facility Contact: Scott Winn
Title: Plant Manager
AIRS No.: 067-00001

N	Does this facility qualify for a general permit (i.e. concrete batch plant, hot-mix asphalt plant)? Y/N
Y	Did this permit require engineering analysis? Y/N
N	Is this a PSD permit Y/N (IDAPA 58.01.01.205.04)

Emissions Inventory			
Pollutant	Annual Emissions Increase (T/yr)	Annual Emissions Reduction (T/yr)	Annual Emissions Change (T/yr)
NO_X	39.4	0	39.4
SO_2	1.3	0	1.3
CO	19.4	0	19.4
PM10	1.8	0	1.8
VOC	14.7	0	14.7
TAPS/HAPS	0.0	0	0.0
Total:	62.2	0	**76.6**
Fee Due	**$ 5,000.00**		

Comments: